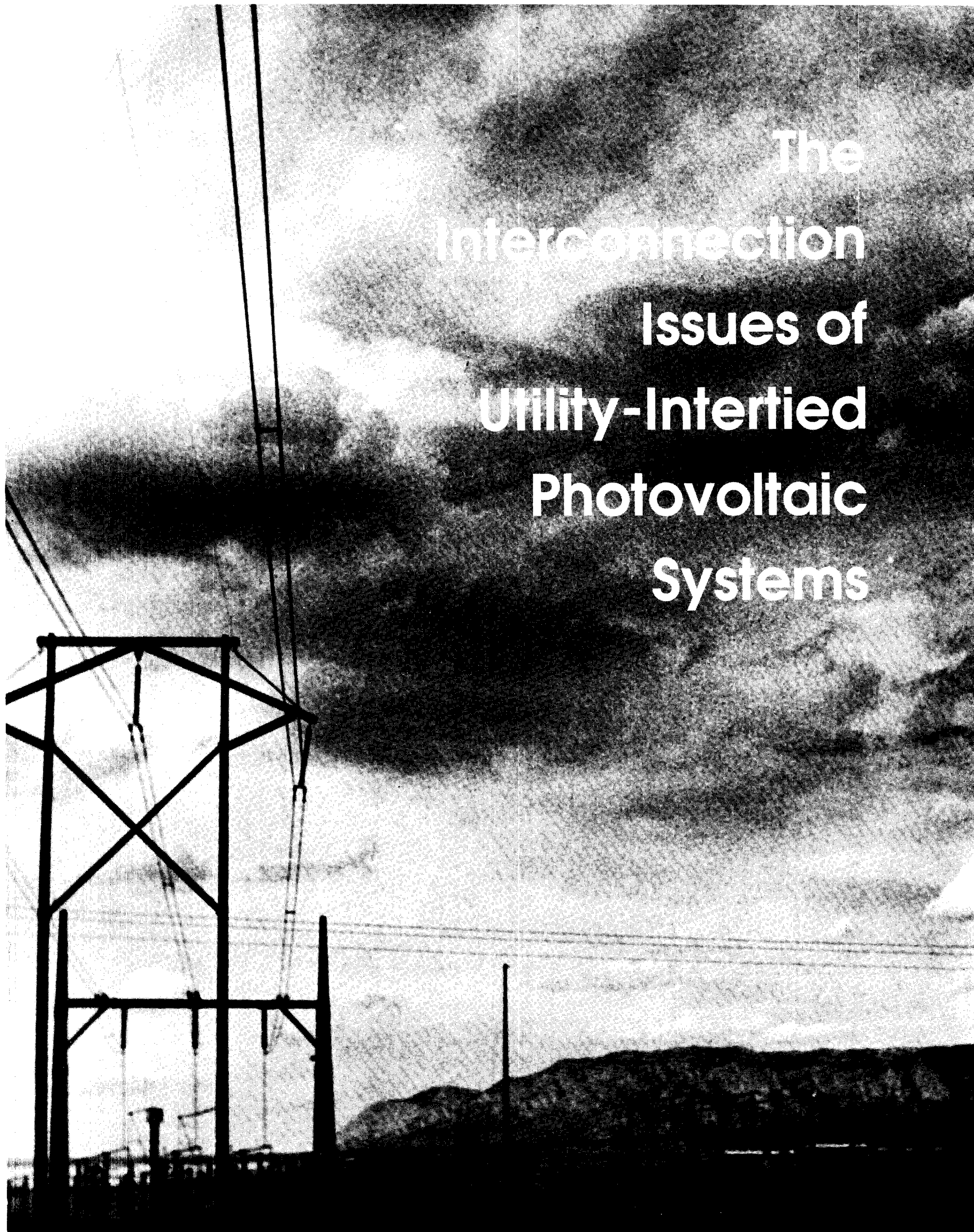
The Interconnection Issues of Utility-Intertied Photovoltaic Systems



Distribution Category
UC-1290

SAND87-3146
Unlimited Release
Reprinted June 1997

The Interconnection Issues of Utility-Intertied Photovoltaic Systems

John Stevens
Photovoltaic Systems Research Division
Sandia National Laboratories
Albuquerque, NM 87185

Abstract

For photovoltaics to realize its potential as a significant contributor to U.S. energy requirements, photovoltaic systems must be capable of benign interconnections with existing electric utility systems. Technical questions have to be addressed in these interconnections, including such issues as how the photovoltaic system will respond to the dynamics of the utility system, and how it will impact the quality of the utility's voltage and power. The answers to these questions may impact the methods of using photovoltaics and the mode of deploying arrays, both of which will ultimately affect the value of the systems' energy. In an effort to understand these questions and their answers, the National Photovoltaic Program has amassed a significant data base concerning photovoltaic/utility interface issues. This research has created an understanding of the issues involving such an interface and has helped resolve any potential problems with it. This report discusses technical issues associated directly with the photovoltaic/utility interface.

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The Power Conditioning Subsystem: High-Frequency vs. Low-Frequency

To examine interface questions, one examines the PCS, which is the interface hardware between the PV array and the utility system. One of the important differences in PCSs is the switching frequency, which varies from line frequency to several kilohertz or higher. Those units, which switch at line frequency are not attempting to perform waveshaping, but are switching simply to achieve positive and negative half-cycles from the PV array's dc input. Although it is possible to have a line-frequency PCS that employs forced commutation, this is not an economical choice, so line-frequency PCSs are normally line-commutated; that is, they rely on zero crossings in the utility waveform to provide switching signals. A direct result is that the line-commutated PCS will require significant reactive power from the utility while converting dc real power to ac real power. In other words, line-commutated PCSs have a significant (0.4 to 0.8) lagging power factor.

High-frequency power conditioners have two internal switching stages. They have a high-frequency stage that is used to simulate a rectified sinewave from the PV dc by such techniques as pulse-width modulation. A second switching stage then operates at line-frequency to "unfold" the rectified sinewave into a full sinewave. These units are self-oscillating in the sense that switching commands, which determine both dc voltage regulation and ac waveshape, are internally generated. This gives the designer flexibility to have switching occur at whatever point of the intertied utility's waveform desired, giving control over the PV system's power factor. High-frequency PCSs also take advantage of solid-state controls to monitor their own condition as well as that of the utility, allowing controlled response to such utility dynamics as varying frequency and voltage or utility outages.

Research and Development Approach

Different PCS designs have different waveforms and different power factors, and are affected in different ways by the utility system's dynamics. Therefore a PV system's impact on a utility is a direct product of the power conditioner's design. The DOE program has worked with several PCS manufacturers in an effort to provide power conditioners that interact with utilities in a totally benign manner. The basic approach has been to evaluate PCS performance and to improve the power conditioner where necessary. The only area in which this approach does not work is voltage flicker, for which the design of the utility system is more of a factor than the design of the PCS. The dynamics of a utility require that the PV system respond properly to variations of a long-term nature, such as the change in voltage due to a voltage regulator change, or of a short-term nature, such as a surge caused by lightning or by utility switching. When there is a utility outage, the system must also respond properly by automatically disconnecting from the utility system. These dynamic issues are addressed most economically in the PCS design, thus avoiding the cost of additional interfacing equipment.

A program to improve the PCS began with several parallel investigations to determine utility interface requirements on the power conditioner.[1] These requirements were then distributed for utility comment in a joint effort including the Electric Power Research Institute (EPRI), DOE, and several research organizations.[2] Sandia evaluated the recommendations and reduced them to a set of specifications. These specifications were then, and continue to be, used to guide development programs for power conditioner hardware.

As the hardware emerged from these development programs, DOE recognized a need for a detailed engineering evaluation program, and the assignment was given to Sandia. In the evaluation effort, a great deal of attention was given to the details of the power conditioner/utility interface. Special test equipment was developed to provide a completely instrumented and controlled "utility" for full-power testing up to 75 kW. This facility and details of utility compatibility tests are described in Bower et al.[3] and Key.[4]

Testing has been underway for several years, and a great deal has been learned. Modifications and improvements have been made in the test requirements, instrumentation, and detailed test procedures—the power conditioners undergoing evaluation have been improved as a result. Key and Bower[5] detail general performance goals and test equipment, instrumentation and procedures; performance results are documented in individual reports for each power conditioner.[6–9]

Generally the performance results are quite favorable. Indeed, high-frequency PCSs have harmonic and power-factor levels well within standards proposed by the IEEE.[10] However, PCS development and testing alone cannot alleviate concerns. Efforts have also been directed toward gaining a thorough understanding of the PCS's operating environment, including studying the utility systems to which a PCS will be interconnected. Studies have been, and continue to be, performed both by utilities and by non-utilities in order to gain insight into the dynamics and existing harmonic levels of utility systems.

Harmonics

Distortion in a power system (that is, the presence of frequencies other than 60 Hz) is generally undesirable. An exception is the intentional superposition of high-frequency signals for control and data acquisition. Harmonics, frequencies that are integer multiples of 60 Hz, are the most common type of power system distortion. Generally, low-order odd harmonics (3rd, 5th, 7th, 9th) are most common and most troublesome on utility systems. Power at these frequencies can shorten the life of various electrical devices by increased heating of electrical insulation and voltage stress due to coincident peaks in 60 Hz and harmonic frequencies. Harmonic injection into utility systems isn't unique to photovoltaics, but it is becoming more common with every new piece of electronic or magnetic equipment that is connected to the utility grid. Concurrently, sensitivity to harmonics is increasing as more devices become dependent on sensing zero-crossings (which can appear to shift because of harmonics) to control internal switching. In addition, utilities are installing more shunt capacitors to optimize distribution systems, and this increases the potential for harmonic problems because of the increased harmonic impedance created by parallel resonance.

Harmonics are usually injected into a utility in the form of *current* harmonics. With the notable exception of telephone interference, problems are caused by harmonic *voltage* being impressed at the terminals of the affected equipment. [A discussion of harmonics and telephone interference is included as an appendix to Ranade. [11]] If the voltage waveform at the terminals of the equipment of interest has little or no distortion, there will be no harmonic impact on the equipment, no matter what level of harmonic current might be present. This is because the utility system impedance, which is in parallel with the load impedance, is significantly lower than load impedance and provides a path for the harmonic current away from the load.

The problems arise when shunt capacitors are connected to distribution systems. These capacitors, when added to a system that already has shunt inductance in the form of load, can form parallel resonance at various frequencies. Many times such an arrangement on a distribution line creates resonance in the third- to ninth-harmonic range, which can be particularly troublesome because these frequencies tend to be prevalent in utility systems. The lower harmonics also tend to have more energy than higher harmonics, thus making them potentially more damaging.

Parallel resonance is manifested by a sharp increase in impedance at the resonant frequency, which translates into increased voltage distortion from a given level of harmonic current. This current may be causing no problem at other, non-resonant points on the system.

Load changes, as occur continually on a utility feeder, have an important impact on parallel resonance. As the parallel resistance is decreased (that is, resistive load is increased) the *magnitude* of the resonant impedance is decreased, thus decreasing voltage distortion. Also, as the parallel inductance is decreased (again, inductive load is increased) the resonant *frequency* increases. These two factors can combine in such a manner that, although a lightly loaded feeder may have resonance problems, as the normal daily increase in load occurs, the problems disappear. This is fortunate when considering harmonic output from a photovoltaic system, because the PV system output tends to increase at the same time loads increase.

The Photovoltaic Power Conditioner and Harmonics

The waveshaping method in the inverter section of a PCS is the prime determinant of the harmonic content of the PCS output. If the waveshaping results in a PCS output unacceptably high in harmonics, then the output can be filtered to achieve any desired harmonic specification. There are several important points relative to harmonics that should be borne in mind when comparing inverter designs, so that the proper perspective is maintained. These points are

Commutation method: changes from a positive current to a negative current, thus creating alternating current.

Switching frequency: determines the number of steps available per cycle to simulate a sinewave. More steps usually means a better simulation of a sinewave.

Output filtering: reshapes the ac output current

PCS power rating: requires different waveshaping techniques at 5 kW than at 500 kW.

These topics are interrelated, making it difficult to address one without the others. The driving force for making these trade-off decisions is economic, which will become clear as the discussion progresses. For example, if harmonic limitation is necessary, then filtering, commutation method, and switching frequency all affect the PCS design. Specifically, the availability of switching devices (power rating and switching speed) for self-commutated units and the cost of filtering for line-commutated units dictate that self-commutated PCSs switched at 4 kHz or greater are most economical for single-phase applications up to the 10-kW size. Similarly, self-commutated designs switched at 2 to 4 kHz are suited for three-phase applications up to the 25-kW size range, above which a filtered, line-commutated, 12-pulse unit shows superior economics. These general statements change with the rapidly changing power electronics industry, but the trend remains the same.

Commutation Method. Line-commutated PCSs are switched by the utility voltage driving the PCS current through zero and are thus inherently simpler and less costly than force-commutated units, which rely on internal circuitry to maintain frequency control and initiate switching. The comment is often heard that line-commutated PCSs have a higher harmonic content than self-commutated units. Although this may be a fact of commercially available hardware, there is no technical reason that it must be true. Line commutation simply means that the PCS output bridge is switched from positive to negative conduction when the utility voltage passes through zero, thus reversing the following (lagging) inverter current. This same commutation function is accomplished in a self-commutated PCS by an internal signal to the same switches. A self-commutated PCS with a 60-Hz switching frequency will have the same current harmonic content as a line-commutated unit (which also is switched at 60 Hz). As far as harmonics are concerned, the importance of self-commutation is the ability to select an appropriate switching frequency, as discussed in the next section.

There is one difference between 60-Hz switching with a line-commutated unit versus one that is self-commutated. The line-commutated unit, while switching at current zero, is not in phase with the voltage zero and thus a short, or "commutation notch," appears in the voltage waveform. This commutation notch contributes to harmonic as well as non-harmonic distortion. Distortion from the commutation notch is not of the same magnitude as that characteristic of the PCS switching scheme. The commutation notch appears to play an insignificant role in harmonics from small, dispersed PV systems,[12] although it is of concern as a source of noise and stress in high-energy-density power systems, as may be found in an industrial or commercial facility. Self-commutation, besides providing switching frequency flexibility, provides notch-free operation and control over the output current/voltage phase relation by controlling the switching angle, thus controlling the power factor.

Switching Frequency. This variable can be utilized to reduce harmonic output. Since the PCS output is actually a series of discrete steps, the smaller these steps, that is, the higher the switching frequency, the closer the approximation to a sinewave. In addition, higher switching frequency implies higher frequency characteristic harmonics with lower harmonic power, both contributing to simplifying any filtering requirements. However high-frequency switching is not all good. It requires a self-commutated unit, which is inherently more complex than a line-commutated unit because of the requirement for switching control circuitry. Also there are losses associated with switching, which can result in high-frequency devices having a bit lower efficiency than those with lower switching frequencies.[13]

Today the question of switching frequency is most important to single-phase, and therefore small, PCSs as discussed under "power rating." Switching frequency may become important to larger, three-phase units in the future as manufacturers begin to take advantage of new devices that are capable of handling large amounts of power while switching at higher frequencies. This will enable them to economically manufacture high-frequency units in larger, three-phase ratings, thus saving the cost of filtering.

Output Filtering. Filtering can be an economic trade-off against switching frequency. Traditional three-phase units (as are normally found today) are line-commutated, which implies low frequency, requiring the use of an output filter in applications in which limiting harmonic injection is important. A three-phase PCS can be switched as a 12-pulse device, allowing relatively inexpensive filtering (because the lowest characteristc harmonic is the 11th [14]), and this is today's technique of choice. Today a filtered 12-pulse unit in any size larger than about 25 kW is cheaper in terms of first cost, plus the value of energy lost, than a comparably sized high-frequency PCS. On the other hand, filtering a single-phase PCS (which is switched as a "2-pulse" device, contributing significant third harmonics) is not as attractive as filtering a three-phase unit because, as mentioned previously, the lower order harmonics are more costly to filter, requiring a relatively large and expensive filter.

Power Rating. Power rating in itself has nothing to do with harmonic output on a percent distortion basis. The impact of power rating on the design of a PCS is based on the availability of the switching device (its speed and power handling abilities). At low power requirements, high-speed devices such as transistors are readily available, making high-frequency switching feasible. Consider that any utility-intertied equipment of less than about 10 kW is usually single phase. A PV system of less than 10 kW will also normally be single phase. In single-phase applications where limiting harmonics is necessary, a self-commutated PCS is usually more attractive than a filtered line-commutated PCS.

For a system large enough to be three-phase, a line-commutated 12-pulse PCS with appropriate filtering will give good results. However for single-phase systems, a PCS switched at line-frequency without filtering will have substantial harmonics. Measurements at Sandia National Laboratories have shown a 6-kW line-frequency single-phase PCS to vary between 7.8% and 32% current total harmonic distortion (THD) at full rated output, depending on both PV array voltage and utility voltage.[9] Figure 2 is a graph of the harmonic output of this same unit as measured at Arizona State University (as part of a Sandia contract with the Salt River Project), which demonstrates the trend very well. On the other hand, a high-frequency, single-phase 4-kW PCS has shown current THD ranging between 1% and 3% in testing at Sandia.[6] Figure 3 displays harmonic output of this unit as measured by ASU under the same Salt River Project contract. It should be noted that the harmonic output of a PCS is not only dependent on the individual design, but on other factors such as ac and dc voltage levels and the utility's ambient harmonic level, seen in the difference between the results reported by Sandia and ASU. However, the important message is the general trend. Both sets of measurements show significantly higher harmonic content from the line-frequency unit than from the high-frequency unit.

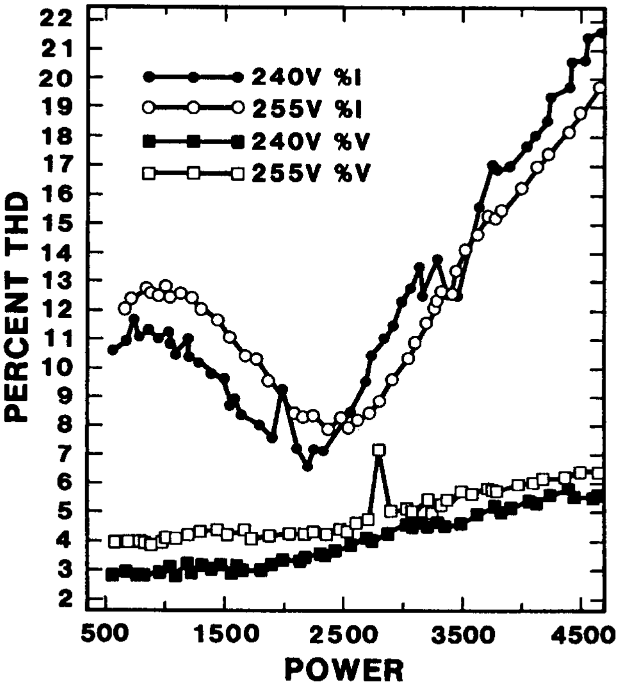


Figure 2. Total Harmonic Distortion From a Low-Frequency PCS

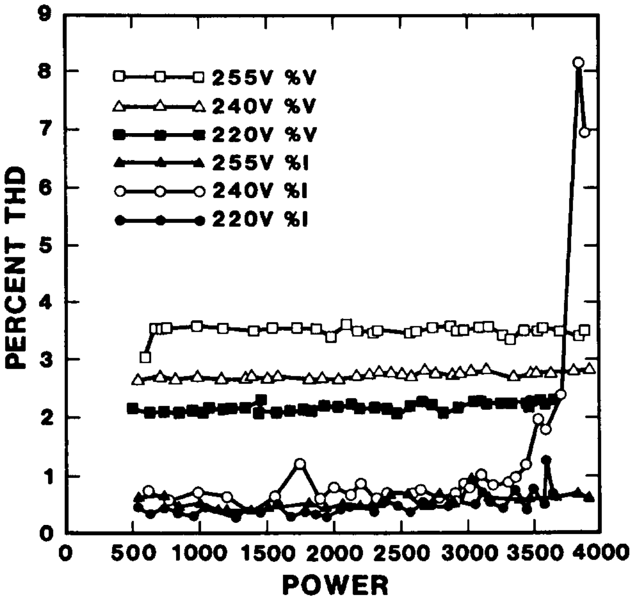


Figure 3. Total Harmonic Distortion From a High-Frequency PCS

Selected Comparative Results

A comparison of harmonic output from high- and low-frequency PCSs with several household appliances was performed by the Alabama Solar Energy Center, as shown in Figure 4.[15] The first two devices on the graph are high-frequency PV PCSs; their actual harmonic output is on the same order as a black and white television set. The third item on the graph is a low-frequency, line-commutated PV PCS. The harmonic output current of this unit is substantially higher than the first two PCSs, and is roughly one-third higher than that of a window air conditioner. Although this output seems high, there are probably many residential feeders on which the average home has more than one window air conditioner with no resultant harmonic problem, and the probability that 50% of the homes will have PV systems is low.[16]

These same measurements also demonstrate some of the difficulty in setting harmonic limit standards. Harmonic distortion limits are usually set as "X" percent harmonic distortion. Although this is probably the best approach to addressing harmonic limits, care must be taken in doing so, as illustrated in Figure 5. In this graph, percent distortion has been charted instead of actual current and it illustrates the potential problem in using percent distortion as a limiting factor. For example, if 5% third-harmonic distortion were set as a limit, it would preclude the use of black and white TVs, personal computers, and window fans. This implies that harmonic limits must consider not only percent distortion, but also the magnitude of distortion current. The black and white TV will not cause harmonic problems, because 90% of .14 amps does not usually matter.

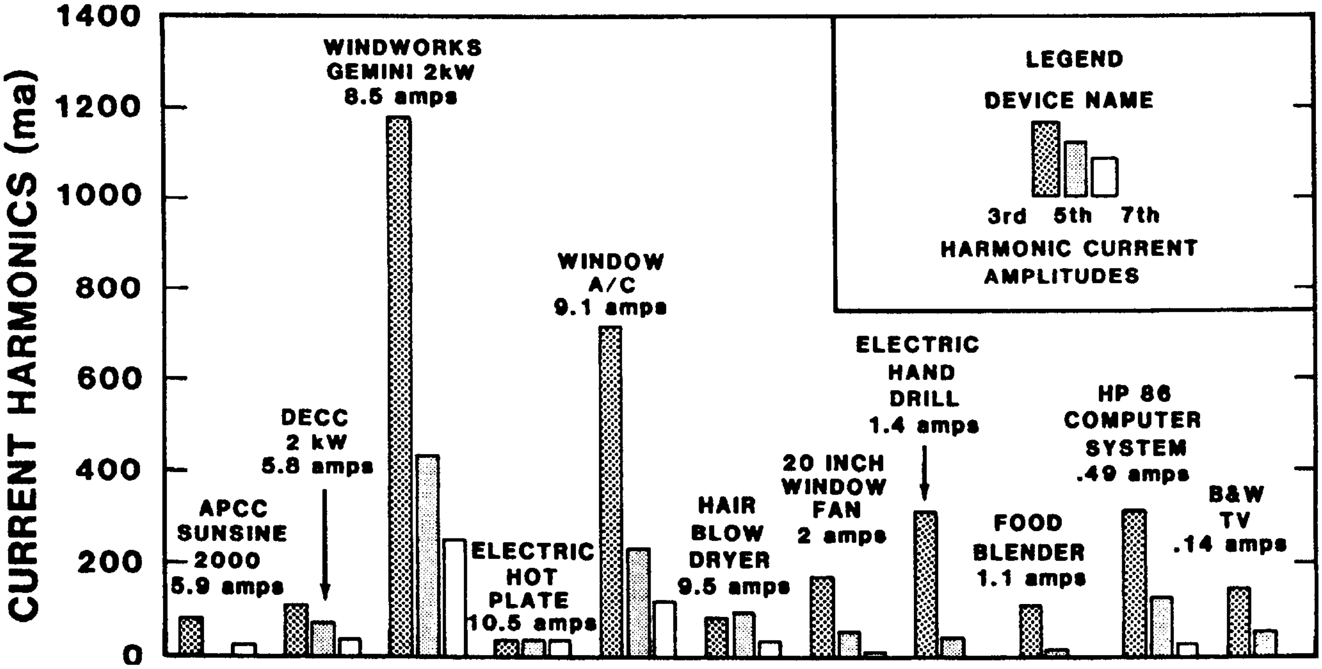


Figure 4. Harmonic Current From PCSs Compared With Other Common Loads

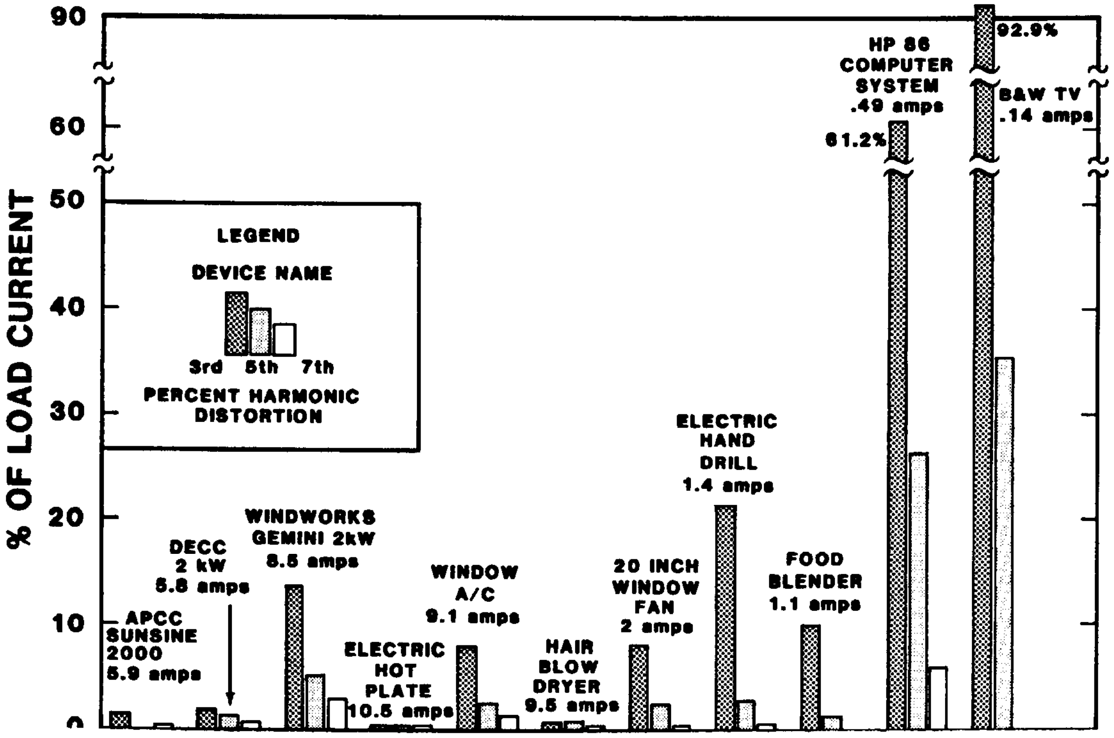


Figure 5. Percent Distortion of Current From PCSs Compared to Other Common Loads

Summary of Power Conditioning Subsystem Harmonics

Although photovoltaic generating systems have the potential to inject significant quantities of harmonic current into an interconnected utility, the technology exists to insure that this does not occur. In sizes at which the PV power conditioner can economically be a self-commutated unit switched at high frequency, the switching pattern can be such that the output waveform closely resembles a sinewave with low distortion. If a three-phase PCS is utilized, a line-commutated 12-pulse inverter can be utilized, which is easily filtered. In either case, harmonics can be limited to whatever level is required.

The impact of a given level of harmonic current injection on a distribution system is determined by the system impedance. High system impedance at a specific frequency results in high voltage distortion from the injected harmonic current, and distortion of the voltage at the terminals of a device is generally what causes problems. Also, parallel resonance increases impedance to levels that cause harmonic problems. Parallel resonance can be viewed as a function of line loading and capacitor placement; however, relocation of shunt capacitors can alter the resonant frequency as well as the magnitude of the resonant impedance. In addition, daily increases in load lower the impedance magnitude as well as shift the resonant point to a higher frequency. These changes are exactly what is required if one is concerned about possible harmonic problems from PV systems. Utilities typically experience high load during the day, when the PV output is present, and low load at night, when the PV systems are off. Generally the daily load increase dampens the effect of harmonics at the same time of day that PV system output is high.

Selected Study Results

Experimental and analytical efforts have been made to quantify the impacts of harmonics to aid in establishing limits that are acceptable to utilities and are not unduly restrictive to owners of PV systems.

As a baseline for this discussion, the existing IEEE Standard 519 for harmonic distortion should be noted. Basically, it states that harmonics should be limited so that THD of the voltage waveform does not exceed 5% on primary distribution lines or 8% on secondaries. These values are generally used when analyzing systems for excessive distortion. IEEE 519 is presently being extensively rewritten, and these values will probably be changed. Moreover, the entire method of determining acceptable levels may be altered. For the moment, the existing version of IEEE 519 is the best we have.

Georgia Tech Study. An extensive harmonics measurement program was undertaken by the Georgia Institute of Technology under the direction of several southeastern utilities and Sandia. The purpose of this effort was to identify existing harmonics on utility systems in order to better appreciate the environment in which PV systems will be deployed, specifically regarding the level of harmonic distortion presently on distribution lines. Tables 1 through 4 summarize the results of several hundred measurements taken on a relatively high-capacity (low-impedance) 25-kV line. Tables 1 and 2 show the maximum voltage THD to be roughly 3%, and the maximum current THD at the same point to be nearly 13.5%. Note that this 13.5% current THD occurred for a line that was lightly loaded (3.6 MW on a line that is rated for at least 20 MW). As the loading increases, thus decreasing the parallel impedance of the line, the effect of current harmonics on voltage harmonics is damped because of the lowered parallel impedance.

Table 1. Current Harmonic Statistics on Distribution Line at Capacitor Bank

Number of Samples : 253
Sampling Interval : 15 Min

Order	Min	Max	Ave	StD
FUND	82.5 A	84.2 A	83.38 A	0.424 A
3	1.823 %	3.521 %	2.881 %	0.345 %
5	4.721 %	12.790 %	8.786 %	1.425 %
7	1.802 %	5.593 %	4.181 %	0.824 %
9	0.339 %	1.717 %	0.731 %	0.293 %
11	1.112 %	2.542 %	1.796 %	0.319 %
13	0.306 %	0.949 %	0.554 %	0.135 %
15	0.037 %	0.415 %	0.313 %	0.081 %
THD	6.456 %	13.493 %	10.419 %	1.266 %

Table 2. Voltage Harmonic Statistics on Distribution Line at Capacitor Bank

Number of Samples : 253
Sampling Interval : 15 Min

Order	Min	Max	Ave	StD
FUND	14823.83 V	15382.06 V	15067.76 V	109.95 V
3	1.741 %	2.395 %	2.040 %	0.115 %
5	0.290 %	2.049 %	1.065 %	0.307 %
7	0.444 %	1.004 %	0.804 %	0.125 %
9	0.016 %	0.132 %	0.079 %	0.031 %
11	0.127 %	0.243 %	0.176 %	0.028 %
13	0.047 %	0.095 %	0.072 %	0.008 %
15	0.012 %	0.028 %	0.019 %	0.005 %
THD	1.993 %	2.994 %	2.464 %	0.203 %

Also note from Tables 3 and 4 that the average third-harmonic current at the substation (where the voltage THD is less than 2%) is approximately 5% of 200 amps, or 10 amps. It is interesting to estimate how many PV systems would be required to produce this amount of harmonic distortion. Utilizing the results of the John Long Home study,[12] which indicates 4 amps third-harmonic current at full output from a line-commutated 6-kW PCS (a low-frequency, high-harmonic unit), it can be seen that 10 amps of third-harmonic current is equivalent to 15 kW of low-frequency PCSs. To see its equivalent on the distribution primary, multiply by the transformer turns ratio of 60 (240-volt secondary, 25-kV primary), which shows that 10 amps on the primary is equivalent to 900 kW per phase, or 2700 kW of PV generation (assuming all third-harmonic injection is in phase, the worst case). This is equivalent to 450 6-kW PV systems. As stated earlier, the actual harmonic output is a function of several parameters and will vary. This simple analysis demonstrates that it requires many PV systems, even utilizing harmonically rich PCSs, to generate the same harmonic levels that are ambient on this system, levels substantially below those recommended by IEEE 519 (and they appear to be causing no problems). This same simple analysis can be performed for a high-frequency low-distortion unit, which typically injects 0.13 amps third-harmonic current from a 4-kW unit.[6] In this case, it would require 77 such units, or over 300 kW, to produce 10 amps third harmonic on the secondary. Utilizing the same turns ratio of 60, this transforms to over 18 MW *per phase* of PV generation, well in excess of the line capacity of 20 MW for all three phases, to inject 10 amps of third-harmonic current on this distribution line.

Table 3. Current Harmonic Statistics on Distribution Line at Substation

Number of Samples : 576
Sampling Interval : 15 Min

Order	Min	Max	Ave	StD
FUND	150.00 A	267.00 A	203.16 A	30.42 A
3	3.017 %	7.237 %	5.113 %	0.766 %
5	2.928 %	10.870 %	6.567 %	1.547 %
7	0.735 %	4.823 %	2.920 %	0.994 %
9	0.000 %	0.643 %	0.234 %	0.129 %
11	0.187 %	1.558 %	0.656 %	0.257 %
13	0.000 %	0.629 %	0.234 %	0.122 %
15	0.000 %	0.327 %	0.023 %	0.075 %
THD	5.253 %	13.041 %	8.918 %	1.697 %

Table 4. Voltage Harmonic Statistics on Distribution Line at Substation

Number of Samples : 576
Sampling Interval : 15 Min

Order	Min	Max	Ave	StD
FUND	14436.00 V	14904.00 V	14643.31 V	86.93 V
3	1.147 %	2.092 %	1.542 %	0.197 %
5	0.349 %	1.884 %	0.984 %	0.304 %
7	0.157 %	0.454 %	0.280 %	0.044 %
9	0.050 %	0.177 %	0.110 %	0.027 %
11	0.073 %	0.213 %	0.102 %	0.023 %
13	0.008 %	0.058 %	0.025 %	0.008 %
15	0.033 %	0.067 %	0.049 %	0.006 %
THD	1.225 %	2.824 %	1.868 %	0.309 %

These relatively generous quantities of PV systems are based on limiting voltage THD to 2%, whereas IEEE 519 allows 5% on a 25-kV line. The probability is that if a few megawatts of residential PV systems are added to a single distribution feeder, the PCSs will be from several different manufacturers and will have differing harmonic characteristics. This suggests that a significant percentage of a feeder's capacity could be met with PV generation and could have no harmonic problems. Of course, one must never forget that resonance problems can occur. However, resonance problems can usually be cured by altering the deployment mode of shunt capacitors.[17]

A relatively low-impedance feeder is discussed above, but others have still lower impedance. For example, a point in the downtown network of Consolidated Edison in Manhattan had a measured current THD of 27%, which resulted in a voltage THD of only 1%. This is obviously an exception and is only noted to make the point that system impedance can be quite variable.

A 12.5-kW feeder in Alabama, which is probably more typical than the one in the Consolidated Edison system, was measured at the same time as the 25-kV feeder studied by Georgia Tech. Tables 5 and 6 show current and voltage harmonics for it. Noting the figures from the "average" column, 2% current THD produces 1% voltage THD. Also note that the maximum values show 6% current THD producing 2% voltage THD, which demonstrates the non-linearity of harmonic distortion and reinforces the difficulty in analysis.

Table 5. Voltage Harmonic Statistics on Alabama Distribution Line

Order	Average	Std. Dev.	Minimum	Maximum
FUND	7285.429 V	42.317 V	7200.000 V	7350.000 V
3	0.226 %	0.044 %	0.114 %	0.398 %
5	0.788 %	0.484 %	0.040 %	1.901 %
7	0.449 %	0.111 %	0.087 %	1.053 %
9	0.124 %	0.108 %	0.001 %	0.457 %
11	0.067 %	0.038 %	0.013 %	0.149 %
13	0.038 %	0.020 %	0.010 %	0.092 %
15	0.005 %	0.002 %	0.001 %	0.014 %
THD	1.018 %	0.368 %	0.462 %	1.963 %

Table 6. Current Harmonic Statistics on Alabama Distribution Line

Order	Average	Std. Dev.	Minimum	Maximum
FUND	13.799 amp	5.141 amp	5.350 amp	24.500 amp
3	1.502 %	0.733 %	0.132 %	3.944 %
5	0.830 %	0.605 %	0.052 %	4.523 %
7	0.826 %	0.271 %	0.061 %	2.321 %
9	0.390 %	0.204 %	0.021 %	0.841 %
11	0.200 %	0.092 %	0.005 %	0.624 %
13	0.366 %	0.088 %	0.049 %	0.602 %
15	0.251 %	0.112 %	0.077 %	0.572 %
THD	2.107 %	0.814 %	0.941 %	6.123 %

An analysis similar to that performed above can be carried out on this feeder to establish a rough idea of the extent to which PV systems can be added and still remain within voltage THD limits. Again, the voltage THD targeted will be 2% (because we have data in the "maximum" column for 2%), even though IEEE 519 allows 5%. From the "maximum" columns in Tables 5 and 6, note that 2% voltage THD is associated with approximately 6% current THD, or about 1 amp of third-harmonic current on the 12.5-kV system. This corresponds to 30 amps per phase at 240 volts, or 90 amps of injected third-harmonic current. Again assuming 4 amps third harmonic from the 6-kW line-commutated PCS, and all third-harmonic current in phase, 132 kW of PV generation on this feeder using harmonically rich PCSs would be equivalent to the ambient harmonic level. The same harmonic level would be produced by 2.7 MW of PV generation using the lower harmonic PCSs.

The preceding discussion illustrates two important points:

1. Using simplified methods for analysis, which give very conservative results, a substantial number of small harmonic generators can be accommodated on a utility distribution line. A more rigorous analysis would give more optimistic results because of the effects of loads shunting harmonics from the system and the cancellation effects of harmonics which aren't in phase.
2. The actual impact is highly dependent on the distribution line's configuration, making it extremely difficult to set general guidelines.

New Mexico State University Study. Another study initiated by Sandia, which included both measurements and analysis, was performed by New Mexico State University at the Southwest (SW) Regional Experiment Station (RES). This study included a lower capacity feeder rated at 2.4 kV and 5 MW. Some of the important results of this study[11] are as follows:

- Ambient current and voltage distortion are dominated by system loading rather than by the PV systems at the RES. Harmonic current from the RES can, however, be seen along the distribution line.
- A capacitor bank on this line creates resonance in the fifth to ninth harmonic range.
- Analysis indicates that expansion of the PV systems at the RES to 25% of the feeder capacity is possible while maintaining the voltage THD within 5%. Dispersal of the systems along the feeder, or elimination of the harmonically rich PCSs would allow further increases in PV penetration.
- The impact of line resistance and load on significantly damping resonance is demonstrated.

John Long Study. An extensive project was performed jointly by Oak Ridge National Laboratories and McGraw Edison to monitor and analyze what has come to be known as the "John Long Home" in Phoenix, Arizona. [17] The installation consisted of a 6.6-kW residential PV system with a low-frequency (high-harmonic) PCS on a 12.5-kV line. This single home was a prototype for a proposed 100-home subdivision. Although the subdivision has not yet been realized, John Long Homes has installed a 190-kW PV system to serve 22 homes in Phoenix. The Oak Ridge/McGraw Edison project consisted of performing harmonic measurements at the residence to characterize both the existing harmonics and those of the PCS, and then analyzing the impact of adding 100 such PCSs to each of two different Arizona Public Service Company feeders.

When performing the simulation, the absolute worst case was first sought in order to put an upper bound on the harmonic impact. This was achieved by arranging the line capacitors to make the system resonant at the third harmonic (the largest component of the PCS distortion), and installing absolutely no load. In this worst-case scenario the projected 660 kW of PV generation from the proposed homes caused a 4.8% voltage THD (within the 5% IEEE limits) on one of the proposed feeders and 6.2% on the other. When the same case was run with no shunt capacitors on the system, the voltage THD was in the range of 2.5% for both lines. Using the same worst case capacitor arrangement, but adding 2 MW of resistive load to each feeder, the THD values were reduced to 3.6% for each feeder. When all capacitors were connected (as opposed to only those that allowed tuning the circuit to the third harmonic), but with no load, the THD values were 2.4% for each feeder.

These results reinforce points previously made. The impact of dispersed small harmonic sources is dependent on line characteristics, particularly capacitor placement and connected load. If harmonic problems do appear, they can normally be resolved by manipulating the shunt capacitors. In this study, the scenarios that appear to be most realistic (that is, with some load at the time of PV generation) maintain acceptably low voltage THD.

Harmonic Modelling of Loads. Even these acceptably low levels may be higher than will be seen in reality. As the researchers on the John Long project point out in Dugan,[17] recent work by Jack Fitzer at the University of Texas at Arlington indicates that the method of representing motor loads in the harmonic modelling process is important to the results.[18] Fitzer's work shows that on a feeder such as this, which will probably have as high as 80% motor loads, modelling the load as a series R-L circuit sized for the proper power and power factor will give results dramatically worse than if a detailed load model were used. Figure 6 graphically illustrates this difference, showing third-harmonic voltage as a function of position on a distribution line for the same amount of load using the two different models. Fitzer developed the detailed load model by performing laboratory tests on motors similar to those found in refrigerators and air conditioners. It seems apparent from this work that the actual impedance of motor loads is low enough at harmonic frequencies that significant amounts of harmonic current are shunted from the distribution line, resulting in lower harmonic distortion than would be predicted using a series R-L model. This result can be reflected back to all the cases discussed previously, indicating that the analytical results, although favorable, would have been more favorable using the detailed load model.

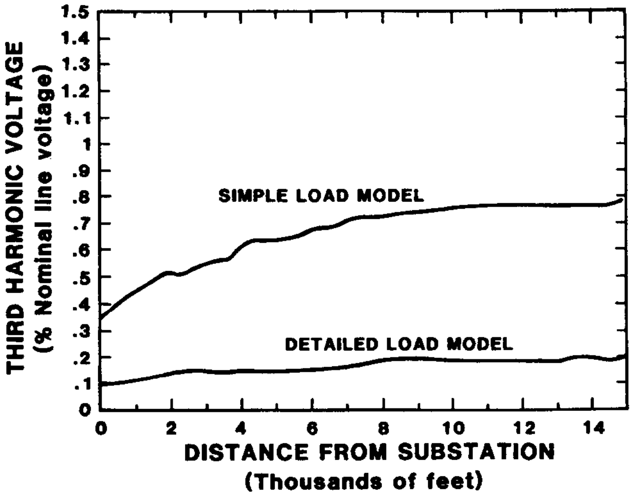


Figure 6. Harmonic Prediction From Detailed and Simple Load Models

Sacramento Municipal Utility District Study. The final set of measurements to be discussed is that on the Sacramento Municipal Utility District's 1-MW PV plant, known as PV-1. This installation is on a 12.5-kV line and utilizes a twelve-pulse filtered PCS. Measurements were taken with and without the filter to determine (1) if the filter was performing its proper function and, (2) if the system could be operated without the filter and maintain acceptable harmonic distortion levels.[19] Results showed that with the PV system operating and the filters connected, voltage THD averaged between 1.1% and 1.3%. However, with the PV system operating and the filters disconnected, the average value only increased to 1.5% - 1.6%. The dominant harmonic with the PV system on, whether the filters were connected or not, was the 11th (which is to be expected with a 12-pulse device), whereas the 5th was dominant when the PV system was off.

One Utility's Perspective

The following quote from a Georgia Power Company (GPC) report for Sandia is an important summary of the potential impact of PV systems on harmonics: "When GPC entered into this contract with SNL [Sandia National Laboratories], we had serious misgivings about the effect that harmonics produced by the static power converters (SPCs) of residential PV systems would have on the utility system. (Author's note: SPC is another term for PCS.) Based on the percentage total harmonic distortion (THD) of the SPC output current, especially at low loads, this appears to be a problem. However, microwave ovens, television sets, and home computers are frequently worse in terms of percentage THD. Taken in perspective (total current of all harmonics) the problem no longer seems as serious." This statement reflects this utility's changed viewpoint; at the beginning of the contract effort GPC felt that PV systems would cause a real harmonic problem and at the end of the contract the company found that PV systems were no worse than most residential appliances.

Conclusions About Harmonics

Although there is certainly no doubt that excessive harmonics do cause problems to utilities, distributed photovoltaic systems, even at high penetration levels on a given feeder, do not appear to be serious contributors to those problems. It has been demonstrated through measurement and analysis that, depending on the particular PCS and line, from 10% to 100% of a line's capacity can be provided by PV generation without exceeding existing IEEE standards for voltage distortion. It has also been demonstrated that the analytical techniques normally used to determine harmonic impacts give substantially conservative results (by as much as a factor of 4). By performing the same analysis utilizing the Fitzer load model, a more favorable and realistic result will be obtained. The difficulty in harmonic analysis is the possibility of resonance, which will increase the voltage THD resulting from a given level of current THD.

Problems such as this can normally be remedied by altering the deployment of shunt capacitors. The existing analytical techniques for examining the impact of harmonics should be consolidated, utilizing realistic load models, to allow an engineer to examine the impact of harmonic injection on any distribution system of interest.

Power Factor

The term "power factor" is normally used when discussing a device that consumes both watts and vars (vars describe power that is 90° out of phase from watts, also known as reactive volt-amps). The power factor is a measure of the relative magnitudes of watts and vars that make up a load. The power factor ranges from zero lagging through one, to zero leading; zero lagging indicates all var load, one indicates all watt load, and zero leading indicates all capacitive load, which actually supplies vars. Most homes have a power factor of roughly .9 lagging. The reason power factor is an issue with PV systems is that line-commutated PCSs consume vars while delivering watts, which can be thought of as an unfair economic burden to the utility (and, ultimately, the rest of the utility customers), since it requires the utility to buy watts while delivering vars for free. Self-commutated PCSs do not necessarily consume vars and, in fact, can be designed to any power factor, including leading power factor, which produces vars. Because of the complicated situation in which watts are *produced* and vars *consumed*, we will quickly cease referring to "power factor" and start referring to "var consumption."

Briefly, resistive loads (incandescent lights, resistance heaters, etc.) consume watts. Inductive loads (motors, transformers, anything with coils of wire) consume vars in addition to watts. Capacitive loads (capacitors are not a common type of load) *produce* vars. The power to supply both the required watts and vars to meet a utility's load must be produced and transmitted in order for the utility to meet its commitments. Because a significant number of var-consuming devices are on most utility systems, the utility tries to meet the var demand by installing shunt capacitors on distribution lines, thereby relieving the necessity of generating vars at a central power plant and transmitting them along the entire system. (Transmitting vars involves energy loss, just as transmitting watts does, and creates voltage drop.) The important considerations when discussing var consumption are the cost, transmission, and voltage regulation impacts. Voltage regulation impacts are discussed under the heading "Flicker."

One aspect of var consumption is purely economic. Residential utility customers are billed based only on their watt-hour consumption because typical residential revenue meters do not respond to vars. If a PV system is added to a residence and that PV system supplies only real power (that is, operates at unity power factor), the utility loses the revenue for watts that have been displaced by PV watts, but must continue to supply the var demand of the residence. If, in addition, the PV system demands vars, the utility must supply the PV var demand in addition to the residential var demand. In either case the utility is not compensated for its costs, and its actual revenue is reduced because fewer watt-hours are sold to the customer. A Southern California Edison engineer comments (in an unpublished contract report written for the author): "In order to be completely equitable, it would be desirable to have the local generation supply the reactive demand of the local load which it is carrying. Since this value would be impractical to determine, a reasonable compromise is to have the local generation operate at 1.0 pF so that, at least, it does not impose any additional reactive demand on the utility." This concept suggests the use of a high-frequency PCS that has been designed to neither consume nor generate vars.

Flicker

Flicker refers to the dimming and brightening of lights caused by voltage fluctuations. It can be quite troublesome, because it generates customer complaints that require man-hours for response. The underlying voltage fluctuations can cause premature wear of the utility's voltage regulating equipment. Flicker is half the story with var consumption. The current required to deliver vars imposes a voltage drop on the utility's lines just as the current to deliver watts does. Therefore the method of handling var consumption will impact voltage drop on the distribution line. Again quoting from the above-cited unpublished Southern California Edison report:

> Utilities must control the voltage of their distribution circuits in order to keep the utilization voltage within established limits. In general, the problem is one of limiting the maximum voltage at locations near the source substation and limiting the minimum voltage at locations near the end of the feeder.
>
> When local generation is installed to supply real power, the reduction in real power load on the feeder tends to cause the voltage to increase near

> the point where the generation is applied. Conversely, reactive power demand by the local generation causes the voltage to fall. It can be shown mathematically that these two effects will compensate each other (i.e., no voltage change) when the power factor angle of the generation is the complement of the short-circuit power factor angle of the distribution system. Since the latter value for distribution systems is in the range of 45°-60°, the optimum range of power factor angles for the local generation is 30°-45°. This corresponds to lagging power factors of 0.7-0.85. Lagging power factors below 0.85 may cause the voltage to decline when the generation is on and power factors below 0.7 will definitely cause voltage drop. This voltage drop is most undesirable when the generation is located near the end of a feeder since it may reduce the voltage below the minimum limits. [Author's note: A thorough discussion of calculating the appropriate generation power factor for a given feeder impedance, along with results of application of the technique, can be found in Fitzer et al.[18]]
>
> Higher power factors than 0.85 may cause the voltage to rise rather than fall. This is not of major importance since the effect is small at locations near the source station where the voltage is already high. At locations near the end of the feeder, where the voltage rise effect is a maximum, the effect is usually beneficial since the voltage at such locations tends to be low.

Since the economic aspect of the PCS power factor favors unity, and the voltage flicker aspect appears to favor a power factor of 0.85 or higher, most installations will have the most favorable impact with a unity power factor; that is, no var consumption. In the unusual case of an installation that could impact voltage adversely (for example, an unusually large PV system on a very low-capacity line), the technique discussed by Fitzer[18] to match generator power factor with line impedance (as mentioned in the above quote) will provide a system with the least voltage flicker impact.

It is important to note that a properly calibrated PCS will not force the voltage out of established limits, because the PCS has voltage-limit trip points built in. If a very large PV system affects line voltage so that the voltage goes outside of the preset limits, then the PCS will trip and the line will be left in its normal mode.

Other Voltage Impacts. There is the possibility that PV generation will affect utility equipment, even though there is no apparent impact on voltage flicker. The regulating equipment found on many utility systems operates in 5/8% voltage steps. That is, any voltage change of 5/8% or greater, will result in a regulator operation if sustained adequately long (several seconds to a couple of minutes, depending on the utility). Regulator maintenance requirements and life expectancy are both directly related to the number of operations. A Georgia Power Company report summarizes its effort to investigate the impact of a 20% penetration of PV systems. The results show that 20% penetration, when reduced to 25% of normal output by a passing cloud, will result in a 0.9% voltage change, adequate to cause a regulator step change. If such a cloud were to pass over a residential feeder once an hour, the result would be a 20% increase in regulator operations, with resultant increased maintenance and loss of equipment life.

Fitzer, however, points out that such cloud patterns may not be as common as one might suspect.[18] Fitzer studied two actual feeders, one that covered a service area approximately 1.2 by 2.5 miles, the other covering a rural service area approximately 8 by 14 miles. In order to obtain the 0.9% voltage change, the entire area of the feeder that contains PV systems must change from full sun to full cloud cover. Although this is certainly possible, it is probably not the normal scenario for cloud cover. Two other scenarios seem more probable. One is the typical scattered cloudiness during "fair weather," which would lead to individual PV systems increasing and decreasing their output, but the overall PV generation on a feeder would probably remain relatively constant at some reduced value. The other most likely scenario is movement of an entire cloud front, which will indeed change all PV systems from full to reduced ouput, but this probably would occur less than once a day. Utilities may want to perform their own voltage impact analyses in this particular area. For this reason, a computer model is presently being developed under Sandia contract to provide the capability to do this, and it includes the capability to select appropriate cloud types. Again, it should be borne in mind that if voltage fluctuation is a serious problem for a utility, the problem can be cured by requiring the PV PCS to operate at a fixed power factor (only possible with self-commutated PCSs).

Utility System Dynamics

It is important that a PCS have the ability to recognize a utility outage and respond properly to that outage by disconnecting from the utility. As for the propensity for run-on, or islanding, of these systems after utility disconnect, the laboratory results are quite favorable. However, this was not always the case. Every unit tested ran-on initially. Developmental work with manufacturers was required to obtain the results given in this report. The initial goal in run-on testing was to have a PCS disconnect in less than 20 cycles under fault conditions to ensure that the PV system was off-line for potential utility reclosing. This would avoid the possibility that a utility might reclose on an unsynchronized PV system and would only be required in the case of disconnect due to a fault, because reclosing will not normally be active in the case of manual switching.

Further investigations showed that there could be two different criteria for the time required before PCS disconnect. In the case of a fault, characterized by a voltage excursion, disconnect in 20 cycles or less is desirable to protect the PCS. In the case of manual disconnect, which is not accompanied nor preceded by a voltage excursion or followed by a reclosure, the time to disconnect can be significantly longer. In this case, after a switch is opened, a disconnection simply must occur before a person might touch the line. For example, consider a lineman opening a switch to perform maintenance. The time between opening the switch and actually beginning work on the line will be several minutes. Thus PCS disconnect in 1 minute or less should be satisfactory. The actual time required to complete PCS shutdown has not been established. Several of the utilities involved in contract work for Sandia are considering between 1 and 2 seconds as their target.

Tests Under Fault Conditions

The circuit shown in Figure 7 was used to perform the laboratory testing for fault response. By altering switch positions, either a line-to-line or a line-to-ground fault (on a 120/240-V single-phase system) could be simulated. The response of all units tested was quite predictable and is characterized by the type of curve shown in Figure 8. Note first that the parameter being sensed is voltage rather than current. The reason is that the source, a PV system, is not capable of producing adequate fault current to enable one to reliably select between load current and fault current. Also note that the PCS will remain online for voltage excursions within the ANSI-specified operating range.[20] For excursions outside the normal operating range, the time to disconnect is a function of voltage. For minor voltage excursions, the unit will remain online longer (up to 2/3 second), which will help to ride through temporary voltage dips caused by such things as starting motors. For more significant voltage swings, the unit disconnects much more rapidly. Note, for example that a 50% voltage dip prompts a 5-cycle trip time. Although the curve of Figure 8 is for one specific unit, the general characteristics are seen in all units.

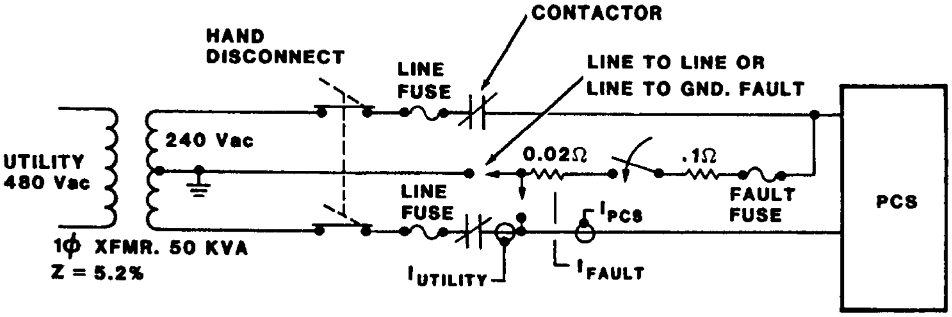


Figure 7. Test Circuit for Fault Response

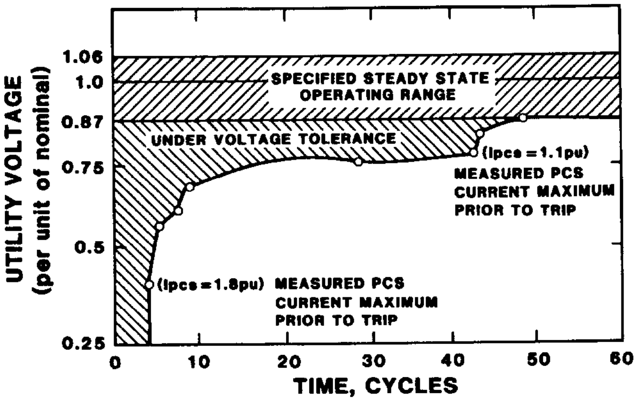


Figure 8. Fault Response of DECC PCS

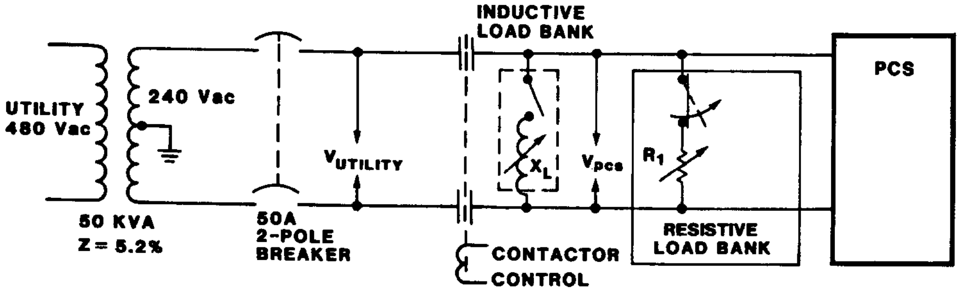
Tests Under No-Fault Disconnect

The laboratory tests for a disconnect in which no fault is involved were performed using the circuit shown in Figure 9. This circuit allows tuning resistive, capacitive, and inductive load banks to various values before disconnect. These tuned loads then remain in the PV system circuit after disconnect, simulating the effect of opening a utility line switch, which isolates the PV system and its associated loads from the utility.

This condition is potentially much more difficult for the PCS to recognize. All of the units, when first received, could be made to run-on indefinitely under the proper conditions of load closely matched to generation. This problem was discussed with the involved manufacturers, and circuits were developed to recognize this condition and disconnect the unit. For the most part, the circuitry developed for the task of recognizing utility disconnects under closely balanced load and generation is proprietary. However, it is generally known that the easiest parameters to monitor for utility disconnect are voltage and frequency. If there is adequate mismatch between load and generation, then either frequency or voltage (or both) will drift, and if they are monitored, trip limits can be established to disconnect the PCS. However, if the load and generation are matched closely enough, voltage and frequency may remain within normal operating limits. Hence, it is necessary to use other techniques to detect the subtle changes that will occur upon utility disconnect.

Utility Testing

The best way to determine whether these devices are acceptable to utilities is to put them in the utilities' hands and ask them to test the units to their own satisfaction. To this end, four contracts were placed by competitive bid. The contractors selected were Southern California Edison Company (SCE), Salt River Project (SRP), Georgia Power Company (GPC) and Public Service Electric and Gas Company (PSE&G). Each contractor was provided with power conditioners from Sandia. All tested these units in their own facilities for their shutdown characteristics and for other qualities. Once each utility felt confident that it knew what to expect from the various units, each designed experiments to test multiple-PV-system run-on at one of the three RES. None of the utilities felt it necessary to perform fault testing in the field because of the earlier results. Only the more subtle disconnects without fault were a concern.



R_1 LOAD SIZED FOR DESIRED PCS STEADY OUTPUT INTO LOAD BANKS

Figure 9. Test Circuit for No-Fault Disconnect

Testing at the Southwest Regional Experiment Station

The first of these tests was performed at the Southwest (SW) Regional Experiment Station (RES). Here SCE and SRP decided to join forces and perform their testing together. Figure 10 shows the configuration at the RES, and Figure 11 details the loads. Note that the smallest increment of capacitive load was 25 kvar and the smallest increment of inductive load was a 1 1/2 hp motor.

These tests were begun by testing each PCS individually, which revealed two cases of continuous run-on. The Gemini unit ran-on continuously when all load except the primary capacitors was disconnected and no isolation transformer was employed. When this same condition was repeated adding resistive load matched to the PCS output, the unit disconnected in 8 cycles. Simply adding the isolation transformer to the continuous run-on configuration resulted in 15 1/2 cycle shutdown. All configurations of resistive and reactive load resulted in run-on no longer than 15 1/2 cycles.

The other case of continuous run-on was seen in a DECC unit (self-commutated) with matched resistive and reactive load. Any other load conditions gave a maximum run-on time of 22 cycles.

For all the other units tested, the maximum run-on time was 49 cycles seen with a TeslaCo PCS (all PCSs tested were self-commutated except the Gemini) with resistive load matched to generation.

After individual units, two units were tested at a time, limiting cases to those that had provided the maximum run-on times for individual units. In these tests, all combinations of two PCSs together, whether similar or dissimilar units, responded better than one unit by itself. There were no cases of continuous run-on.

The final tests involved five PCSs in parallel. Utilizing all combinations of resistive and reactive loading, the longest run-on time recorded was 19 cycles. This robust interaction was a bit of a surprise at the time because most people involved expected some sort of deleterious interaction in which one PCS might view another as the utility, thus exacerbating the islanding problem. In retrospect, it appears that the additional PCSs increased the probability that one unit would recognize the island and disconnect. Once this occurred, the step change in apparent load to the other units was adequate to trip all others.

Although the response of the power conditioners to this series of testing was fairly good, the involved utilities felt uneasy that there was any propensity for run-on. The final report to the author included this statement by the SCE project manager: “It is also recommended that programs be initiated with each of the manufacturers to identify the reasons for the run-on time, and if excessive, modify the existing or develop a new control scheme to prevent run-on upon loss of the utility source.” Sandia has initiated a project to develop a better understanding of run-on.

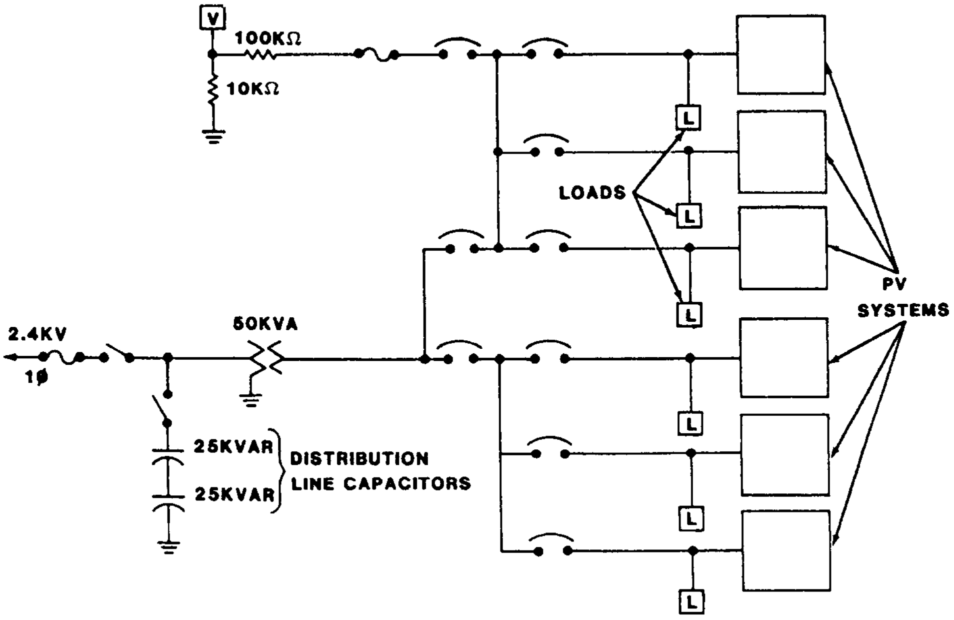


Figure 10. SW RES Power Circuit

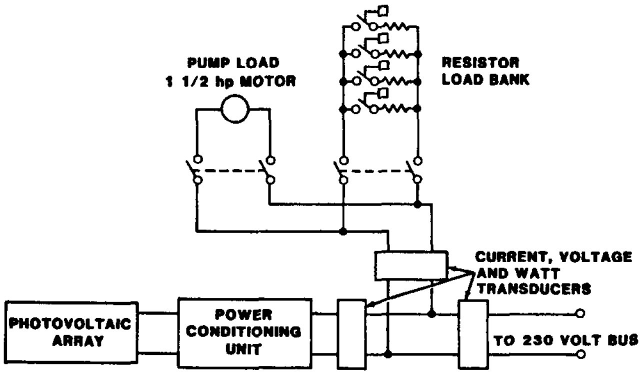

PUMP LOAD
1 1/2 hp MOTOR
RESISTOR
LOAD BANK
CURRENT, VOLTAGE
AND WATT
TRANSDUCERS
PHOTOVOLTAIC
ARRAY
POWER
CONDITIONING
UNIT
TO 230 VOLT BUS

Figure 11. SW RES Loads

Testing at the Northeast Regional Experiment Station

PSE&G performed its islanding experiments at the Northeast (NE) Regional Experiment Station (RES). The basic configuration was similar to that at the SW RES, with variable resistors, motor loads, and primary-side distribution capacitors. Fifty-four cases were run, and most resulted in disconnect in less than 10 cycles. Three cases ran-on for more than 60 cycles, with the longest run-on time being 84 cycles. There were no cases of continuous run-on. PSE&G did not furnish an opinion on the acceptability (or lack thereof) of the results of its testing.

Testing at the Southeast Regional Experiment Station

Georgia Power Company selected the Southeast (SE) Regional Experiment Station (RES) for its islanding experiments. GPC took a slightly different approach to the testing than did the other utilities. The other utilities chose to use fixed increments of reactive load, on the premise that this is what will be encountered on actual distribution feeders, and only to fine tune the resistive load. GPC decided to give itself the ability to fine tune all loads, which required building a load center to use at the SE RES. The load center is shown in Figure 12. Notice that, in addition to variable resistance and variable capacitance, there is also a motor/generator and a synchronous generator. The synchronous generator simulates the effect of an island that includes a synchronous generator (such as some co-generation plants utilize), whereas the motor/generator could simulate either an induction motor or an induction generator as might be found with a wind generator. It is important to note that synchronous generators are not normally found on residential feeders.

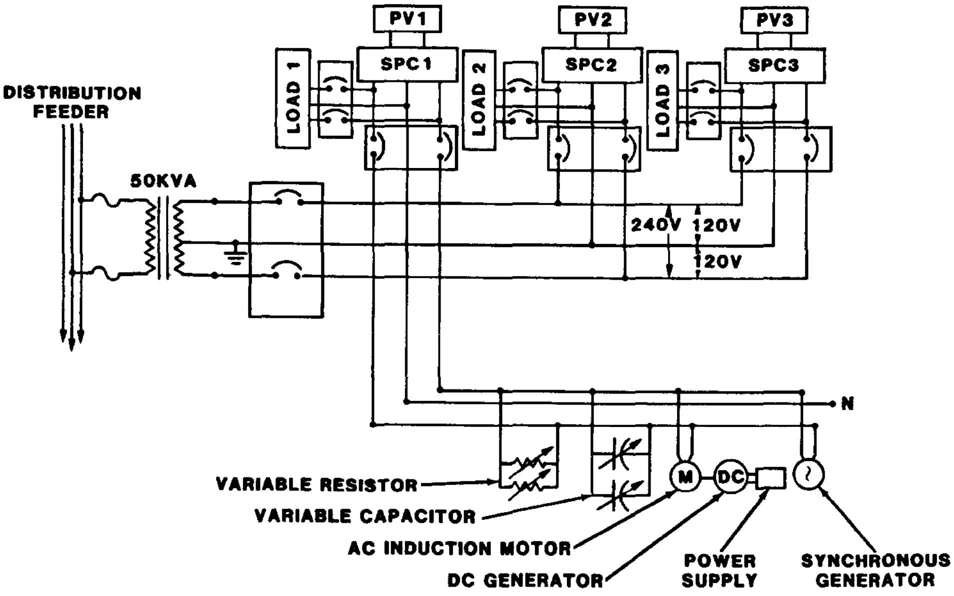

PV1
PV2
PV3
SPC1
SPC2
SPC3
LOAD 1
LOAD 2
LOAD 3
DISTRIBUTION
FEEDER
50KVA
240V
120V
120V
N
M
DC
VARIABLE RESISTOR
VARIABLE CAPACITOR
AC INDUCTION MOTOR
DC GENERATOR
POWER
SUPPLY
SYNCHRONOUS
GENERATOR

Figure 12. SE RES Power Circuit Including G.P.C. Load Center

GPC recorded 49 experimental runs, of which 29 ran-on for longer than 60 cycles and 14 ran-on continuously. The method of selecting run-on tests was by real-time selection. A given test would be run, the results observed, and then alterations made dependent on those results. This method provided GPC with good flexibility to investigate interesting phenomena, but also required real-time analysis. GPC reported that the order of probability of shutdown, from its test results, was 1st APCC, 2nd TeslaCo, 3rd DECC and 4th Gemini. The following is a quote from the GPC report to the author: "It should be noted that an island's chance of survival was practically nil after the shutdown of the first converter when only passive load was used. The survival rate increased with the use of the motor/generator set and increased significantly when the synchronous generator was connected to the system. Results also indicate that chances of sustained islands were slightly better with higher PV generation (more sunshine). However, separation of the first converter at high output would accelerate the shutdown of the remaining converters, because of the increased unbalance between generation and load in the island."

Similar to SCE, GPC concluded that ″Analytical studies may still be needed to set islanding trends on grid connected PV systems.″ These analytical studies are included in the previously mentioned follow-on work.

Comparison of Results

All the utilities involved in this testing experienced run-on to some degree. Those utilities that expressed an opinion felt the reasons for this run-on needed to be addressed to determine the extent to which run-on should be expected. In the case of the SW RES testing, continuous run-on was only experienced in two cases. With the Gemini, run-on was only seen with capacitive and no other load. When the Gemini was connected in parallel to other PCSs, run-on was not a problem. However, the SE RES testing reported that the Gemini would run-on either alone or in parallel with other units feeding resistive and reactive loads as long as there was adequate capacitance to satisfy the var requirements of the Gemini and the mismatch between load and generation was not too severe.

Do these results conflict? At first glance it is tempting to speculate that the load increments at the SW RES were too great to permit fine tuning the load to the PCS output, resulting in well-behaved response from the Gemini. Inspection of the SE RES test results supports this speculation, but the tests were not performed in a manner that allows drawing definite conclusions. For example, a test was run in which 7% load imbalance (resistive and capacitive loads only) caused indefinite run-on. However another test was run in which 3% load imbalance (resistive, capacitive, and induction motor) resulted in shutdown after a little more than 6 seconds. In all cases where the Gemini was tested with other units in parallel, the determining factor in shutdown time was one of the other units, not the Gemini. The shortest shutdown times always involved an APCC.

That the DECC ran-on only when resistive and reactive loads were well matched was substantiated in the SE RES testing. (The NE RES results were so similar to those of the SW RES that comparisons are not of interest. Read "SW RES results" as "SW RES and NE RES results.") The only difference is that the SE RES testing required a rotating load to maintain the run-on.

Whereas the SW RES tests were unable to get any significant run-on with the APCC units, the SE RES experiments did succeed in producing run-on with the APCC units for several seconds, but not continuous run-on.

Conclusions About Islanding

There is a dramatic difference between a power conditioner's ability to sense the need to disconnect from the utility because of a fault and the need to disconnect because of a circuit that has been opened under no-fault conditions. In the case of a fault, the associated voltage excursion is adequate to achieve rapid and sure PCS disconnect. The opening without a fault is a much more subtle event for the PCS to recognize. However, manufacturers of self-commutated PCSs have developed methods of utility disconnect recognition that work very well under most conditions. All self-commutated PCSs tested would recognize a utility disconnect and respond properly when load watts or vars are more than 20% different than PV watts or vars. However, when the load is carefully selected for the PCS output, most units could be made to run-on, in some cases indefinitely. It should be noted that indefinite run-on, in reality, has a time limit, because this condition assumes that generation and load remain constant. The passage of a cloud or turning on of a refrigerator compressor will probably be adequate to upset the required balance. The degree of balance required could not be determined from these tests, but future tests will investigate this issue.

The line-commutated PCS depended on the lack of proper load to generation balance (including a substantial amount of capacitive load) in order to recognize an islanded condition and initiate disconnect. It was demonstrated that this unit could be forced into a run-on condition simply by selecting the appropriate load. When determining whether this characteristic is troublesome, one must ask if it is probable to isolate a line-commutated PCS with the appropriate loads to support run-on in any actual installation. The requisite net capacitive load is not normally seen in a residence. Should a utility require addition of capacitance in order to balance var consumption of a PV PCS, this could increase the probability of forming an island.

The consensus of the utilities performing the contract work was that sufficient evidence was presented to indicate that run-on can be a problem and that further investigation is required. As a result of this concern, Sandia is completing an effort that will identify the factors influencing run-on. This work involves analytical investigation of the causes of run-on, the parameters to which run-on is sensitive and the size of the windows of sensitivity. By understanding these issues, a determination can be made whether the conditions to support islanding are too remote to worry about, or whether PV PCSs should be designed to be even more sensitive to possible islanding. The results of this effort to better understand islanding will be published as SAND87-7024 approximately 6 months after release of this report.

Summary

The DOE PV program has systematically investigated PV/utility interface issues, and the PV and utility industries were heavily involved in this research. In this report, the results of the effort are described. The issues selected were those that could be addressed at the point of interconnection, as opposed to those that are more utility-wide and are properly addressed as utility operations. The latter are important and are the topic of ongoing research, but are not within the scope of this report. The main conclusions about each topic include:

- **Harmonics**—They cannot be ignored as a general utility system problem. The probability that PV systems will actually cause a harmonic problem is very low. The PCSs available with low harmonic content do not contribute adequate harmonics to cause a problem. The devices with higher harmonic content appear (from both measurements and analysis) also to be low enough in harmonics to avoid problems, except in unusual conditions of system resonance at the appropriate harmonic frequency.
- **Power factor and voltage flicker**—These two subjects are heavily interdependent. In fact, by selecting an appropriate power factor, any power swings seen by the PV system will result in no voltage deviation. Investigations show that, because of the nature of cloud movement and its impact on PV systems, voltage fluctuations will not normally be a concern. A computer tool is being developed presently that will allow a utility to investigate this effect on its own system. Because of the lack of impact from voltage fluctuation, power factor becomes solely an economic question.
- **Utility dynamics**—The PV PCS provides a robust interface with the utility, responding satisfactorily to most utility dynamic situations. The possible exception is the case of a utility disconnect without a fault. Testing experience has shown that in some cases the PV system will continue operating. Ongoing research indicates that the required balance between load and generation and the type of load that will support this "islanding" is quite limited. A current research effort will add clarification to this subject.

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Printing History

Printed November 1988
Second Printing, March 1991
Third Printing, July 1992
Fourth Printing, June 1993
Fifth Printing, August 1994
Sixth Printing, May 1996
Seventh Printing, June 1997

☆ U.S. GOVERNMENT PRINTING OFFICE: 1997–573–127–42134

SANDIA NATIONAL LABORATORIES
SAND87-3146